Chapter 3: Profile of the Electric Power Industry

Introduction

This profile compiles and analyzes economic and financial data for the electric power generating industry. It provides information on the structure and overall performance of the industry and explains important trends that may influence the nature and magnitude of economic impacts from the proposed §316(b) New Facility Regulation. While this profile does not specifically address new electric generating facilities subject to the proposed rule, the information presented is nevertheless relevant to new facilities as it describes the market into which new facilities must enter and the existing facilities against which they will compete.

The electric power industry is one of the most extensively studied industries. The Energy Information Administration (EIA), among others, publishes a multitude of reports, documents, and studies on an annual basis. This profile is not intended to duplicate those efforts. Rather, this profile compiles, summarizes, and presents those industry data that are important in the context of the proposed §316(b) New Facility Regulation. For more information on general concepts, trends, and developments in the electric power industry, the last section of this profile, "References," presents a select list of other publications on the industry.

The remainder of this profile is organized as follows:

- Section 3.1 provides a brief overview of the industry, including descriptions of major industry sectors, types of generating facilities, and the entities that own generating facilities.
- Section 3.2 provides data on industry production and capacity.
- Section 3.3 focuses on existing §316(b) facilities. Facilities affected by the proposed rule are new steam electric facilities that require a National Pollutant Discharge Elimination System (NPDES) permit, operate a CWIS to withdraw cooling water from a water of the United States, and withdraw more than two million gallons per day (MGD). This section provides information on the economic and financial, location and technology characteristics of existing facilities with a CWIS and an NPDES permit.
- Section 3.4 provides a brief discussion of factors affecting the future of the electric power industry, including the status of restructuring, and summarizes forecasts of market conditions through the year 2020.

Chapter Contents

3.1 Industry Overview

This section provides a brief overview of the industry, including descriptions of major industry sectors, types of generating facilities, and the entities that own generating facilities.

3.1.1 Industry Sectors

The electricity business is made up of three major functional service components or sectors: *generation*, *transmission*, and *distribution*. These terms are defined as follows (Beamon, 1998; Joskow, 1997):[1]

- The ***generation*** sector includes the power plants that produce, or "generate," electricity.[2] Electric energy is produced using a specific generating technology, e.g., internal combustion engines and turbines. Turbines can be driven by wind, moving water (hydroelectric), or steam from fossil fuel-fired boilers or nuclear reactions. Other methods of power generation include geothermal or photovoltaic (solar) technologies.

- The ***transmission*** sector can be thought of as the interstate highway system of the business – the large, high-voltage power lines that deliver electricity from power plants to local areas. Electricity transmission involves the "transportation" of electricity from power plants to distribution centers using a complex system. Transmission requires: interconnecting and integrating a number of generating facilities into a stable synchronized alternating current (AC) network; scheduling and dispatching all connected plants to balance the demand and supply of electricity in real time; and managing the system for equipment failures, network constraints, and interaction with other transmission networks.

- The ***distribution*** sector can be thought of as the local delivery system – the relatively low-voltage power lines that bring power to homes and businesses. Electricity distribution relies on a system of wires and transformers along streets and underground to provide electricity to residential, commercial, and industrial consumers. The distribution system involves both the provision of the hardware (e.g., lines, poles, transformers) and a set of retailing functions, such as metering, billing, and various demand management services.

Of the three industry sectors, only electricity generation uses cooling water and is potentially affected by §316(b) regulation. The remainder of this profile will focus on the generation sector of the industry.

[1] Terms highlighted in bold and italic font are defined in the glossary at the end of this chapter.

[2] The terms "plant" and "facility" are used interchangeably throughout this profile.

3.1.2 Prime Movers

Electric power plants use a variety of ***prime movers*** to generate electricity. The type of prime mover used at a given plant is determined based on the type of load the plant is designed to serve, the availability of fuels, and energy requirements. Most prime movers use fossil fuels (coal, petroleum, and natural gas) as an energy source and employ some type of turbine to produce electricity. The six most common prime movers are (U.S. DOE, 2000a):

- ***Steam Turbine:*** Steam turbine, or "steam electric" units require a fuel source to boil water and produce steam that drives the turbine. Either the burning of fossil fuels or a nuclear reaction can be used to produce the heat and steam necessary to generate electricity. These units are generally base load units which are run continuously to serve the minimum load required by the system. Steam electric units generate the majority of electricity produced at power plants in the U.S.

- ***Gas Combustion Turbine:*** Gas turbine units burn a combination of natural gas and distillate oil in a high pressure chamber to produce hot gases that are passed directly through the turbine. Units with this prime mover are generally less than 100 megawatts in size, less efficient than steam turbines, and used for peak load operation serving the highest daily, weekly, or seasonal loads. Gas turbine units have quick startup times and can be installed at a variety of site locations, making them ideal for peak, emergency, and reserve-power requirements.

- ***Combined-Cycle Turbine:*** Combined-cycle units utilize both steam and gas turbine prime mover technologies to increase the efficiency of the gas turbine system. After combusting natural gas in gas turbine units, the hot gases from the turbines are transported to a waste-heat recovery steam boiler where water is heated to produce steam for a second steam turbine. The steam may be produced solely by recovery of gas turbine exhaust or with additional fuel input to the steam boiler. Combined-cycle generating units are generally used for intermediate loads.

- ***Internal Combustion Engines:*** Internal combustion engines contain one or more cylinders in which fuel is combusted to drive a generator. These units are generally about 5 megawatts in size, can be installed on short notice, and can begin producing electricity almost instantaneously. Like gas turbines, internal combustion units are generally used only for peak loads.

- ***Water Turbine:*** Units with water turbines, or "hydroelectric units," use either falling water or the force of a natural river current to spin turbines and produce electricity. These units are used for all types of loads.
- ***Other Prime Movers:*** Other methods of power generation include geothermal, solar, wind, and biomass prime movers. The contribution of these prime movers is small relative to total power production in the U.S., but the role of these prime movers may expand in the future because recent legislation includes incentives for their use.

Table 3-1 provides data on the number of utility and nonutility power plants by prime mover. This table includes all plants that have at least one non-retired unit and that submitted Forms EIA-860A (Annual Electric Generator Report - Utilities) or EIA-860B (Annual Electric Generator Report - Nonutilities) in 1998. Plants that use more than one type of prime mover were classified under the prime mover type that accounts for the largest share of the plant's total electricity generation.

Table 3-1: Number of Utility and Nonutility Plants by Prime Mover, 1998

Prime Mover	Utility†	Nonutility†
	Number of Plants	Number of Plants
Steam Turbine	831	962
Combined-Cycle	40	n/a††
Gas Turbine	315	257
Internal Combustion	615	336
Hydroelectric	1,202	355
Other	39	76
Total	3,042	1,986

† See definition of utility and nonutility in Section 3.1.3.
†† Nonutility combined-cycle turbines are reported by their individual gas and steam components and are therefore not identifyable as combined-cycle units.

Source: Form EIA-860A, 1998; Form EIA-860B, 1998.

Only prime movers with a steam electric generating cycle use substantial amounts of cooling water. These generators include steam turbines and combined-cycle turbines. As a result, the analysis in support of the §316(b) regulation focuses on generating plants with a steam electric prime mover. This profile will, therefore, differentiate between steam electric and other prime movers, and only discuss steam electric generation when referring to §316(b) facilities.

3.1.3 Ownership

The U.S. electric power industry consists of two broad categories of firms that own and operate electric generating plants: utilities and nonutilities. Generally, they can be defined as follows (U.S. DOE, 2000a):

- ***Utility:*** A regulated entity providing electric power, traditionally vertically integrated. Utilities may or may not generate electricity. "Transmission utility" refers to the regulated owner/operator of the transmission system only. "Distribution utility" refers to the regulated owner/operator of the distribution system serving retail customers.
- ***Nonutility:*** Entities that generate power for their own use and/or for sale to utilities and others. Nonutility power producers include cogenerators, small power producers, and independent power producers. Nonutilities do not have a designated franchised service area and do not transmit or distribute electricity.

Utilities can be further divided into three major ownership categories: investor-owned utilities, publicly-owned utilities, and rural electric cooperatives. Each category is discussed below.

a. Investor-Owned Utilities

Investor-owned utilities (IOUs) are for-profit businesses that can take two basic organizational forms: the individual corporation and the holding company. An individual corporation is a single utility company with its own investors; a holding company is a business entity that owns one or more utility companies and may have other diversified holdings as well. Like all businesses, the objective of an IOU is to produce a return for its investors. IOUs are entities with designated franchise areas. They are required to charge reasonable and comparable prices to similar classifications of consumers and give consumers access to services under similar conditions. Most IOUs engage in all three activities: generation, transmission, and distribution. In 1998, IOUs operated 1,610 facilities which accounted for more than 66 percent of all U.S. electric utility generation capacity (U.S. DOE, Form EIA-860B).[3]

b. Publicly-Owned Utilities

Publicly-owned electric utilities can be municipalities, public power districts, state authorities, irrigation projects, and other state agencies established to serve their local municipalities or nearby communities. Excess funds or "profits" from the operation of these utilities are put toward community programs and local government budgets, increasing facility efficiency and capacity, and reducing rates. Federally-owned facilities are also included in this category for the purposes of this profile and analysis. Most municipal utilities are nongenerators engaging solely in the purchase of wholesale electricity for resale and distribution. The larger municipal utilities, as well as state and federal utilities, usually generate, transmit, and distribute electricity. In general, publicly-owned utilities have access to tax-free financing and do not pay certain taxes or dividends, giving them some cost advantages over IOUs.

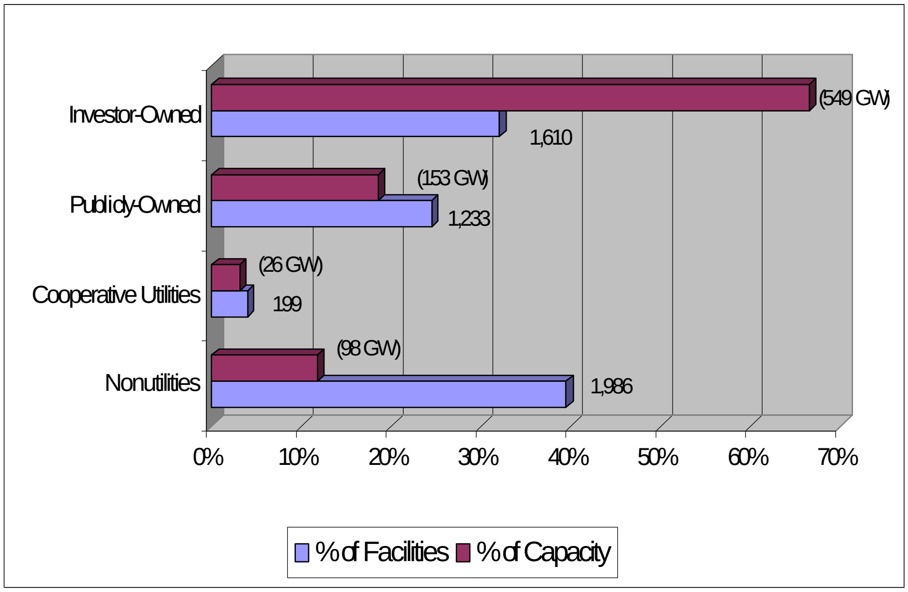
c. Rural Electric Cooperatives

Cooperative electric utilities ("coops") are member-owned entities created to provide electricity to those members. Rural electric cooperatives operated 199 generating facilities in 1998. These utilities, established under the Rural Electrification Act of 1936, provide electricity to small rural and farming communities (usually fewer than 1,500 consumers). Fewer than ten percent of coops generate electricity; most are primarily engaged in distribution. Cooperatives operate in 46 states and are incorporated under state laws. The National Rural Utilities Cooperative Finance Corporation, the Federal Financing Bank, and the Bank of Cooperatives are important sources of financing for these utilities.

Figure 3-1 presents the percent of capacity and generating facilities providing electric power in the U.S. in 1998 by type of ownership. This figure is based on data for all plants that have at least one non-retired unit and that submitted Forms EIA-860A or EIA-860B in 1998. The graphic shows that nonutilities account for the largest percentage of facilities (1,986, or 39 percent), but only represent 12 percent of total U.S. generating capacity. Investor-owned utilities operate the second largest number of facilities and account for 66 percent of total U.S. capacity.

[3] Data for 239 IOU's with at least one non-retired plant.

Figure 3-1: Percent of Capacity and Facilities in the U.S. Electric Power Industry by Ownership Type, 1998



† Capacity is a measure of a generating unit's ability to produce electricity. Capacity is defined as the designed full-load continuous output rating for an electric generating unit.

Source: Form EIA-860A, 1998; Form EIA-861, 1998; Form EIA-860B, 1998.

Plants owned and operated by utilities and nonutilities may be affected differently by the §316(b) regulation due to differing competitive roles in the market. Much of the following discussion therefore differentiates between these two groups.

3.2 Domestic Production

This section presents an overview of U.S. generating capability and electricity generation. Subsection 3.2.1 provides data on generation capability, and Subsection 3.2.2 provides data on generation. Subsection 3.2.3 presents an overview of the geographic distribution of generation plants and capacity.

3.2.1 Generating Capability

Utilities own and operate the majority of the generating capability in the United States (88 percent). Nonutilities owned only 12 percent of the total generating capability in 1998 and produced less than 12 percent of the electricity in the country (U.S. DOE, 1999c). Nonutility capability and generation have increased substantially in the past few years, however, since passage of legislation aimed at increasing competition in the industry. Generation capability for nonutilities has increased 103 percent since 1991, compared with a capability decrease of one percent over the same time period for utilities.[4] Nonutility generation shows an increasing trend since 1991 with the most significant increases occurring in recent years as a result of the move toward a competitive electric power market.

Figure 3-2 shows the growth in utility and nonutility capability from 1991 to 1998. The growth in nonutility capability, combined with a slight decrease in utility capability, has resulted in a modest growth in generating capability overall.

Capacity/Capability

The rating of a generating unit is a measure of its ability to produce electricity. Generator ratings are expressed in megawatts (MW). Capacity and capability are the two common measures:

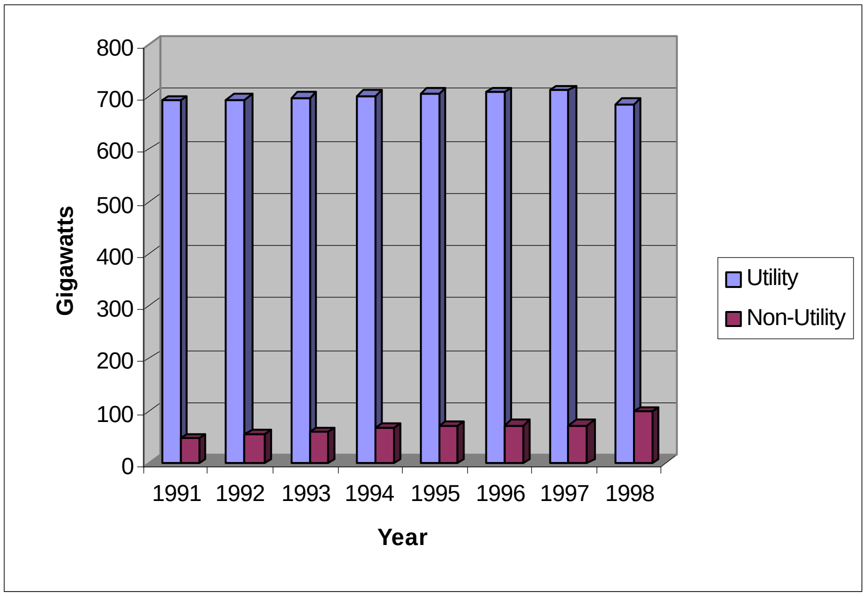
Nameplate capacity is the full-load continuous output rating of the generating unit under specified conditions, as designated by the manufacturer.

Net capability is the steady hourly output that the generating unit is expected to supply to the system load, as demonstrated by test procedures. The capability of the generating unit in the summer is generally less than in the winter due to high ambient-air and cooling-water temperatures, which cause generating units to be less efficient. The nameplate capacity of a generating unit is generally greater than its net capability.

U.S. DOE, 2000a

[4] More accurate data were available starting in 1991, therefore, 1991 was selected as the initial year for trends analysis.

Figure 3-2: Generating Capability, 1991 to 1998



Source: U.S. DOE, 1996b; U.S. DOE,1999c.

3.2.2 Electricity Generation

Total net electricity generation in the U.S. for 1998 was 3,618 billion kWh. Utility-owned plants accounted for 89 percent of this amount. Total net generation has increased by 18 percent over the eight-year period from 1991 to 1998. During this period, nonutilities increased their electricity generation by 71 percent. In comparison, generation by utilities increased by only 14 percent (U.S. DOE, 1999c). This trend is expected to continue with deregulation in the coming years, as more facilities are purchased and built by nonutility power producers.

Table 3-2 shows the change in net generation between 1991 and 1998 by fuel source for utilities and nonutilities.

Measures of Generation

The production of electricity is referred to as generation and is measured in ***kilowatthours (kWh)***. Generation can be measured as:

Gross generation: The total amount of power produced by an electric power plant.

Net generation: Power available to the transmission system beyond that needed to operate plant equipment. For example, around 7% of electricity generated by steam electric units is used to operate equipment.

Electricity available to consumers: Power available for sale to customers. Approximately 8 to 9 percent of net generation is lost during the transmission and distribution process.

U.S. DOE, 2000a

Table 3-2: Net Generation by Energy Source and Ownership Type, 1991 to 1998 (GWh)

Energy Source	Utilities			Nonutilities†			Total		
	1991	1998	% Change	1991	1998	% Change	1991	1998	% Change
Coal	1,551	1,807	17%	39	68	73%	1,590	1,876	18%
Hydropower	280	304	9%	6	14	134%	286	319	11%
Nuclear	613	674	10%	0	0	0%	613	674	10%
Petroleum	111	110	-1%	8	17	124%	119	127	7%
Gas	264	309	17%	127	240	89%	391	550	40%
Renewables††	10	7	-29%	57	66	15%	67	73	8%
Total	2,830	3,212	14%	238	406	71%	3,067	3,618	18%

† Nonutility generation was converted from gross to net generation based on prime mover-specific conversion factors (U.S. DOE, 1996b). As a result of this conversion the total net generation estimates differ slightly from EIA published totals by fuel type.

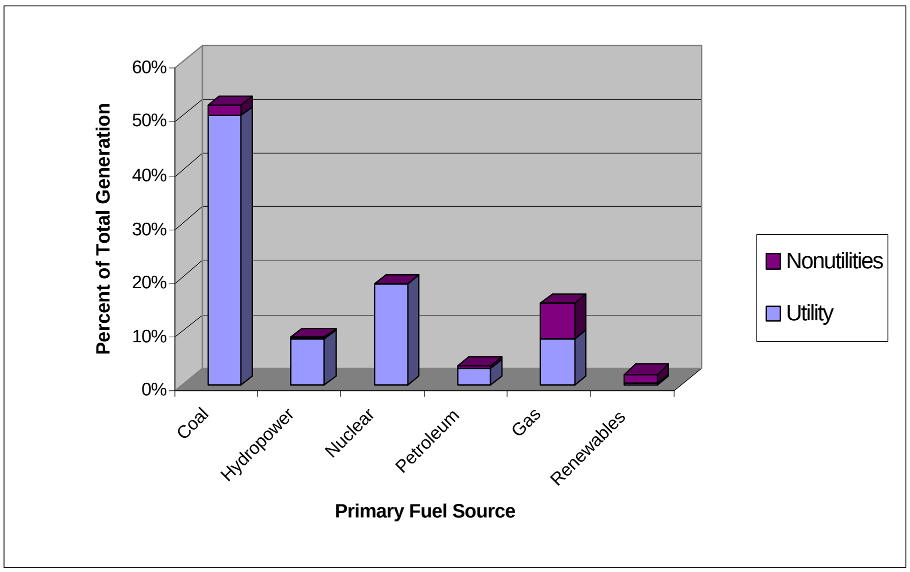
†† Renewables include solar, wind, wood, biomass and geothermal energy sources.

Source: U.S. DOE, 1996b; U.S. DOE,1999c.

As shown in Table 3-2, coal and natural gas generation grew the fastest among the utility fuel source categories, each increasing by 17 percent between 1991 and 1998. Nuclear generation increased by 10 percent, while hydroelectric generation increased by 9 percent. Utility generation from renewable energy sources decreased significantly (29 percent) between 1991 and 1998. Nonutility generation has grown at a much higher rate between 1991 and 1998 with the passage of legislation aimed at increasing competition in the industry. Nonutility hydroelectric generation grew the fastest among the energy source categories, increasing 134 percent from 1991 to 1998. Generation from petroleum-fired facilities, either newly constructed or purchased from utilities, also increased substantially, with a 124 percent increase in generation between 1991 and 1989.

Figure 3-3 shows total net generation for the U.S. by primary fuel source for utilities and nonutilities. Electricity generation from coal-fired plants accounts for 52 percent of total 1998 generation. Electric utilities generate 96 percent (1,807 billion kWh) of the 1,876 billion kWh of electricity generated by coal-fired plants. This represents approximately 56 percent of total utility generation. The remaining 4 percent (68 billion kWh) of coal-fired generation is provided by nonutilities, accounting for 17 percent of total nonutility generation. The second largest source of electricity generation is nuclear power plants, accounting for 19 percent of total generation and approximately 21 percent of total utility generation. Figure 3-3 shows that 100 percent of nuclear generation is owned and operated by utilities. Another significant source of electricity generation is gas fired power plants, which account for 59 percent of nonutility generation and 15 percent of total generation.

Figure 3-3: Percent of Electricity Generation By Primary Fuel Source, 1998



Renewables include biomass, other waste, solar, wind, and geothermal. Hydropower includes conventional and pumped storage.

Source: U.S. DOE,1999c.

The §316(b) regulation will affect facilities differently based on the fuel sources and prime movers used to generate electricity. As mentioned in Section 3.1.2 above, only prime movers with a steam electric generating cycle use substantial amounts of cooling water.

3.2.3 Geographic Distribution

Electricity is a commodity that cannot be stored or easily transported over long distances. As a result, the geographic distribution of power plants is of primary importance to ensure reliable supply of electricity to all customers. The U.S. bulk power system is composed of three major networks, or power grids:

- the ***Eastern Interconnected System***, consisting of one third of the U.S. to the east of the Missouri River;
- the ***Western Interconnected System***, which includes the Southwest and areas west of the Rocky Mountains; and
- the ***Texas Interconnected System***, the smallest of the three, consisting of the majority of Texas.

The Texas system is not connected with the other two systems, while the other two have limited interconnection to each other. The Eastern and Western systems are integrated or have links to the Canadian grid system. The Western and Texas systems have links with Mexico as well.

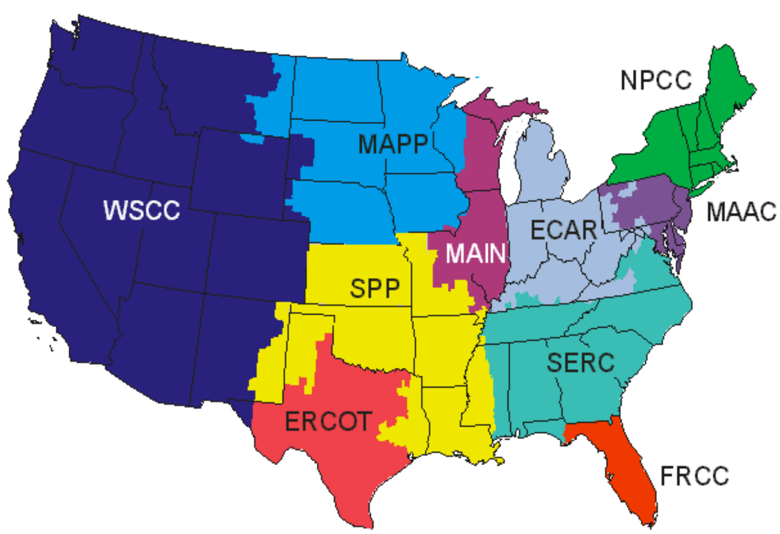
These major networks contain extra-high voltage connections that allow for power transactions from one part of the network to another. Wholesale transactions can take place within these networks to reduce power costs, increase supply options, and ensure system reliability. ***Reliability*** refers to the ability of power systems to meet the demands of consumers at any given time. Efforts to enhance reliability reduce the chances of power outages.

The North American Electric Reliability Council (NERC) is responsible for the overall reliability, planning, and coordination of the power grids. This voluntary organization was formed in 1968 by electric utilities, following a 1965 blackout in the Northeast. NERC is organized into nine regional councils that cover the 48 contiguous states, Hawaii, part of Alaska, and portions of Canada and Mexico. These regional councils are responsible for the overall coordination of bulk power policies that affect their regions' reliability and quality of service. Each NERC region deals with electricity reliability issues in its region, based on available capacity and transmission constraints. The councils also aid in the exchange of information among member utilities in each region and among regions. Service areas of the member utilities determine the boundaries of the NERC regions. Though limited by the larger bulk power grids described in the previous section, NERC regions do not necessarily follow any state boundaries. Figure 3-4 below provides a map of the NERC regions, which include:

- ECAR – East Central Area Reliability Coordination Agreement
- ERCOT – Electric Reliability Council of Texas
- FRCC – Florida Reliability Coordinating Council
- MAAC – Mid-Atlantic Area Council
- MAIN – Mid-America Interconnect Network
- MAPP – Mid-Continent Area Power Pool (U.S.)
- NPCC – Northeast Power Coordinating Council (U.S.)
- SERC – Southeastern Electric Reliability Council
- SPP – Southwest Power Pool
- WSCC – Western Systems Coordinating Council (U.S.)

Alaska and Hawaii are not shown in Figure 3-4. Part of Alaska is covered by the Alaska Systems Coordinating Council (ASCC), an affiliate NERC member. The state of Hawaii also has its own reliability authority (HI).

Figure 3-4: North American Electric Reliability Council (NERC) Regions



Source: EIA, 1996 http://www.eia.doe.gov/cneaf/electricity/chg_str_fuel/html/fig02.html

The §316(b) regulation may affect plants located in different NERC regions differently. Economic characteristics of new facilities affected by the proposed §316(b) New Facility Rule are likely to vary across regions by fuel mix, and the costs of fuel transportation, labor, and construction. Baseline differences in economic characteristics across regions may influence the impact of the §316(b) regulation on profitability, electricity prices, and other impact measures. The proposed §316(b) New Facility Rule may have little or no impact on electricity prices in a particular region if relatively few new plants in the region incur costs under the rule. Conversely, regions that have a large number of new facilities with costs under the proposed §316(b) New Facility Rule could experience a greater impact on electricity prices.

Table 3-3 shows the distribution of all existing utilities, utility-owned plants, and capacity by NERC region. The table shows that while the Mid-Continental Area Power Pool (MAPP) has the largest number of utilities, 24 percent, these utilities only represent five percent of total capacity. Conversely, only five percent of the nation's utilities are located in the Southeastern Electric Reliability Council (SERC). These utilities are generally larger and account for 23 percent of the industry's total generating capacity.

Table 3-3: Distribution of Generation Utilities, Utility Plants, and Capacity by NERC Region, 1998

NERC Region	Generation Utilities		Plants		Capacity	
	Number	% of Total	Number	% of Total	Total MW	% of Total
ASCC	51	6%	166	5%	1,925	0%
ECAR	96	11%	283	9%	110,039	15%
ERCOT	27	3%	106	3%	55,890	8%
FRCC	18	2%	63	2%	38,667	5%
HI	3	0%	16	1%	1,580	0%
MAAC	21	2%	121	4%	56,824	8%
MAIN	62	7%	196	6%	52,916	7%
MAPP	211	24%	398	13%	35,737	5%
NPCC	67	8%	372	12%	46,303	6%
SERC	42	5%	320	11%	164,745	23%
SPP	143	17%	259	9%	45,807	6%
WSCC	125	14%	742	24%	118,349	16%
Total	866	100%	3,042	100%	728,782	100%

Source: Form EIA-860A, 1998; Form EIA-861, 1998.

Table 3-4 shows the distribution of existing nonutility plants and capacity by NERC region. The table shows that the Western Systems Coordinating Council (WSCC) has the largest number of plants, 585, and accounts for the largest share of total nonutility capacity, 29 percent.

Table 3-4: Distribution of Nonutility Plants and Capacity by NERC Region, 1998

NERC Region	Plants		Capacity	
	Number	% of Total	Total MW	% of Total
ASCC	28	1%	401	0%
ECAR	101	5%	7,861	8%
ERCOT	40	2%	7,798	8%
FRCC	62	3%	3,631	4%
HI	8	0%	706	1%
MAAC	95	5%	6,035	6%
MAIN	105	5%	3,361	3%
MAPP	74	4%	1,562	2%
NPCC	384	19%	18,115	19%
SERC	246	12%	13,501	14%
SPP	55	3%	2,319	2%
WSCC	585	29%	27,957	29%
Unknown	203	10%	4,295	4%
Total	1,986	100%	97,542	100%

Source: Form EIA-860B, 1998.

3.3 Existing Plants with CWISs and NPDES Permits

Section 316(b) rulemaking applies to facilities that are point sources under the Clean Water Act and directly withdraw cooling water from a water of the United States. Among power plants, only those facilities employing a steam electric generating technology require cooling water and are therefore of interest to this analysis. Steam electric generating technologies include units with steam electric turbines and combined-cycle units with a steam component.

The following sections describe existing utility and nonutility power plants that would be subject to the proposed §316(b) New Facility Regulation *if they were new facilities*. These are existing facilities that hold a National Pollutant Discharge Elimination System (NPDES) permit and operate a CWIS.[5] The remainder of this chapter will refer to these facilities as "existing §316(b) plants."

Utilities and nonutilities are discussed in separate subsections because the data sources, definitions, and potential factors influencing the magnitude of impacts are different for the two sectors. Each subsection presents the following information:

- ***Ownership type:*** This section discusses existing §316(b) facilities with respect to the entity that owns them. Utilities are classified into investor-

[5] The proposed §316(b) New Facility Regulation only applies to new facilities that withdraw more than two MGD.

owned utilities, rural electric cooperatives, municipalities, and other publicly-owned utilities (see Section 3.1.3). This differentiation is important because EPA is required to separately consider impacts on governments in its regulatory development (see *Chapter 10: UMRA and Other Economic Analyses* for the analysis of government impacts of the proposed §316(b) New Facility Regulation). The utility ownership categories do not apply to nonutilities. The ownership type discussion for nonutilities differentiates between two types of plants: (1) plants that were originally built by nonutility power producers ("original nonutility plants") and (2) plants that used to be owned by utilities but that were sold to nonutilities as the result of industry deregulation ("former utility plants"). For both groups, differentiation by ownership type is important because of the different economic and operational characteristics of the different types.

- ***Ownership size:*** This section presents information on the Small Business Administration (SBA) entity size of the owners of existing §316(b) facilities. EPA is required to consider economic impacts on small entities when developing new regulations (see *Chapter 9: Regulatory Flexibility Analysis/SBREFA* for the small entity analysis of new facilities subject to the proposed §316(b) New Facility Regulation).

- ***Plant size:*** This section discusses the existing §316(b) facilities by the size of their generation capacity. The size of a plant is important because it partly determines its need for cooling water.

- ***Geographic distribution:*** This section discusses plants by NERC region. The geographic distribution of facilities is important because a high concentration of facilities with costs under a regulation could lead to impacts on a regional level. Everything else being equal, the higher the share of plants with costs, the higher the likelihood that there may be economic and/or system reliability impacts as a result the regulation.

- ***Water body and cooling system type:*** This section presents information on the type of water body from which existing §316(b) facilities draw their cooling water and the type of cooling system they operate. The type of source water body determines the compliance requirements of new facilities subject to the proposed §316(b) New Facility Regulation (see *Chapter 6: Regulatory Options* for a discussion of compliance requirements for the different water body types under the proposed §316(b) New Facility Regulation). Cooling systems can be either once-through or recirculating systems.[6] Plants with once-through cooling water systems withdraw between 80 and 98 percent more water than those with recirculating systems.

Water Use by Steam Electric Power Plants

Steam electric generating plants are the single largest industrial users of water in the United States. In 1995:

- steam electric plants withdrew an estimated 190 billion gallons per day, accounting for 39 percent of freshwater use and 47 percent of combined fresh and saline water withdrawals for offstream uses (uses that temporarily or permanently remove water from its source);
- fossil-fuel steam plants accounted for 71 percent of the total water use by the power industry;
- nuclear steam plants and geothermal plants accounted for 29 percent and less than 1 percent, respectively;
- surface water was the source for more than 99 percent of total power industry withdrawals;
- approximately 69 percent of water intake by the power industry was from freshwater sources, 31 percent was from saline sources.

USGS, 1995

3.3.1 Existing §316(b) Utility Plants

EPA identified steam electric prime movers that require cooling water using information from the EIA data collection Forms EIA-767 and EIA-860A.[7] These prime movers include:

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[6] Once-through cooling systems withdraw water from the water body, run the water through condensers, and discharge the water after a single use. Recirculating systems, on the other hand, reuse water withdrawn from the source. These systems take new water into the system only to replenish losses from evaporation or other processes during the cooling process. Recirculating systems use cooling towers or ponds to cool water before passing it through condensers again.

[7] Form EIA-767 (Steam-Electric Plant Operation and Design Report) collects annual data from all steam electric utility plants with a generator nameplate rating of 10 MW or larger. Form EIA-860A (Annual Electric Generator Report) collects data used to create an annual inventory of utilities. The data collected includes: type of prime mover; nameplate rating; energy source; year of initial commercial operation; operating status; cooling water source, and NERC region.

- Atmospheric Fluidized Bed Combustion (AB)
- Combined Cycle Steam Turbine with Supplementary Firing (CA)
- Steam Turbine – Common Header (CH)
- Combined Cycle – Single Shaft (CS)
- Combined Cycle Steam Turbine – Waste Heat Boiler Only (CW)
- Steam Turbine – Geothermal (GE)
- Integrated Coal Gasification Combined Cycle (IG)
- Steam Turbine – Boiling Water Nuclear Reactor (NB)
- Steam Turbine – Graphite Nuclear Reactor (NG)
- Steam Turbine – High Temperature Gas-Cooled Nuclear Reactor (NH)
- Steam Turbine – Pressurized Water Nuclear Reactor (NP)
- Steam Turbine – Solar (SS)
- Steam Turbine – Boiler (ST)

Using this list of steam electric prime movers and Form EIA-860A information on the reported operating status of units, EPA identified 871 facilities that have at least one generating unit with a steam electric prime mover. Additional information from Form EIA-767 and the UDI database was used to determine that 678 of the 871 facilities operate a CWIS and hold an NPDES permit. Table 3-5 provides information on the number of utilities, utility plants, and generating units, and the generating capacity in 1998. The table provides information for the industry as a whole, for the steam electric part of the industry, and for the "§316(b)" part of the industry.

Table 3-5: Number of Utilities, Utility Plants, Units, and Capacity, 1998

	Total†	Steam Electric††		Steam Electric with CWIS and NPDES Permit	
		Number	% of Total	Number	% of Total
Utilities	866	312	36%	221	26%
Plants	3,042	871	29%	678	22%
Units	10,208	2,231	22%	1,781	17%
Nameplate Capacity (MW)	728,782	562,117	77%	509,313	70%

† Includes only generating capacity not permanently shut down or sold to nonutilities.
†† Utilities and plants are listed as steam electric if they have at least one steam electric unit.

Source: Form EIA-860A, 1998; UDI Database, 1994.

Table 3-5 shows that the 871 steam electric plants account for only 29 percent of all plants but for 77 percent of all capacity. The 678 plants that withdraw cooling water from a water of the United States and hold an NPDES permit represent 22 percent of all plants, are owned by 26 percent of all utilities, and account for approximately 70 percent of reported utility generation capacity. The remainder of this section will focus on the 678 utility plants that withdraw from a water of the United States and hold an NPDES permit.

a. Ownership Type

Table 3-6 shows the distribution of the 221 utilities that own the 678 existing §316(b) plants as well as the total generating capacity of these entities by type of ownership. Utilities can be divided into three major ownership categories: investor-owned utilities, publicly-owned utilities (including municipalities, and federal and state-owned utilities), and rural electric cooperatives. Table 3-6 shows that 32 percent of plants operated by investor-owned utilities have a CWIS and an NPDES permit. These 523 facilities account for 77 percent of all existing plants with a CWIS and an NPDES permit. In contrast, the percentage of all plants that have a CWIS and an NPDES permit is much lower for the other ownership types: 21 percent for rural electric cooperatives, 9 percent for municipalities, and 10 percent for other publicly owned utilities.

Table 3-6: Existing Utilities, Plants, and Capacity by Ownership Type, 1998

Ownership Type	Utilities			Plants			Capacity (MW)		
	Total Number of Utilities	Utilities with Plants with CWIS and NPDES		Total Number of Plants	Plants with CWIS and NPDES		Total Capacity	Capacity with CWIS and NPDES	
		Number	% of Total		Number	% of Total		MW	% of Total
Investor-Owned	171	127	74%	1,610	523	32%	549,442	435,358	79%
Coop	68	22	32%	199	41	21%	25,860	16,350	63%
Municipal	566	60	11%	841	76	9%	43,477	17,570	40%
Other Public	61	12	20%	392	38	10%	110,003	40,035	36%
Total	866	221	26%	3,042	678	22%	728,782	509,313	70%

Source: Form EIA-860A, 1998; UDI Database, 1994; Form EIA-861, 1998.

b. Ownership Size

EPA used the Small Business Administration (SBA) small entity size standards for SIC code 4911 (electric output of less than 4 million megawatt hours per year) for investor-owned utilities and rural electric cooperatives, and the population-based size standard established for governmental jurisdictions (population of less than 50,000) for publicly owned utilities to make the small entity determination.[8]

Table 3-7 provides information on the total number of utilities and utility plants owned by small entities by type of ownership. The table shows that 62 of the 221 utilities with existing §316(b) plants, or 28 percent, are small. The size distribution varies considerably by ownership type: only 14, or 11 percent, of all investor-owned utilities with existing §316(b) plants are small, compared 36, or 60 percent, of all municipalities. The same is true on the plant level: only four percent of the 523 existing §316(b) plants owned by a investor-owned utility are owned by a small entity. The corresponding percentages for municipalities, other publicly owned utilities, and electric cooperatives are 49 percent, 13 percent, and 32 percent, respectively.

Table 3-7 also shows the percentage of all small utilities and all plants owned by small utilities that comprise the "§316(b)" part of the industry. Nine percent of all small utilities operate existing §316(b) plants. Again, the distribution varies considerably by ownership type: only seven percent of all small municipal utilities operate a §316(b) plant, compared to 29 percent of all small investor-owned utilities. At the plant level, 11 percent of plants operated by investor-owned small entities have CWISs and NPDES permits compared to only five percent of small municipally-owned plants.

[8] SBA defines "small business" as firms with an annual electric output of four million megawatthours or less and "small governmental jurisdictions" as governments of cities, counties, towns, school districts or special districts with a population of less than 50,000 people.

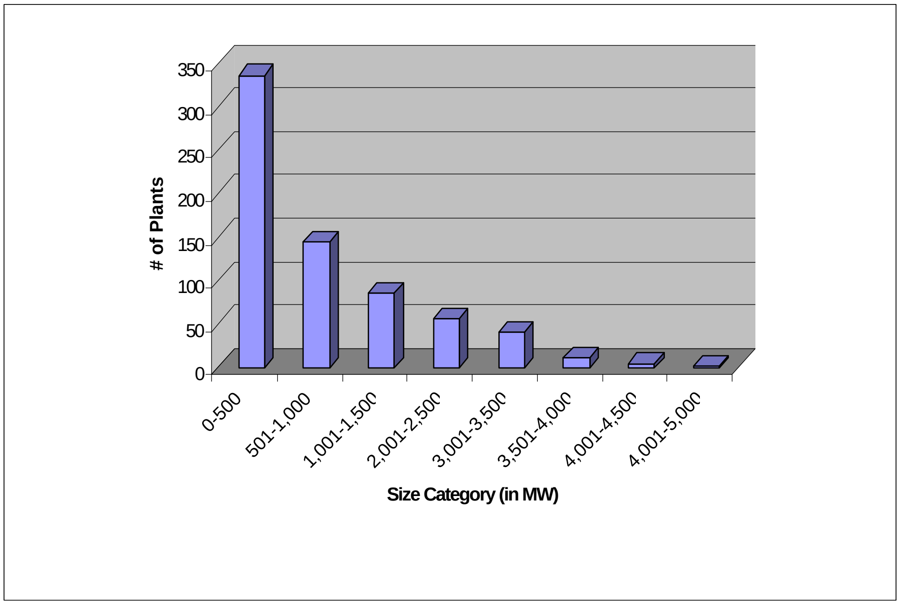
Table 3-7: Small Utilities and Utility Plants by Ownership Type, 1998								
Ownership Type	Total				With CWIS and NPDES Permit			Small with CWIS and NPDES/ Total Small
	Total	Small	Unknown	% Small	Total	Small	% Small	
Utilities								
Investor-Owned	171	48	12	28%	127	14	11%	29%
Coop	68	50	0	74%	22	9	41%	18%
Municipal	566	549	6	97%	60	36	60%	7%
Other Public	61	26	18	43%	12	3	25%	12%
Total	866	673	36	78%	221	62	28%	9%
Plants								
Investor-Owned	1,610	180	48	11%	523	19	4%	11%
Coop	199	145	0	73%	41	13	32%	9%
Municipal	841	765	7	91%	76	37	49%	5%
Other Public	392	82	141	21%	38	5	13%	6%
Total	3,042	1,172	196	39%	678	74	11%	6%

Source: Form EIA-860A, 1998; EIA-861, 1998.

c. Plant Size

EPA also analyzed the steam electric facilities with a CWIS and an NPDES permit with respect to their generating capacity. Of the 678 plants, 336 (50 percent) have a total nameplate capacity of 500 megawatts or less, and 480 (71 percent) have a total capacity of 1,000 megawatts or less. Figure 3-5 presents the distribution of existing utility plants with a CWIS and an NPDES permit by plant size.

Figure 3-5: Number of Existing Utility Plants with CWIS and NPDES Permit by Plant Size, 1998



Source: Form EIA-860A, 1998.

d. Geographic Distribution

Table 3-8 shows the distribution of existing §316(b) utility plants by NERC region. The figure shows that there are considerable differences between the regions in terms of both the number of existing utility plants with a CWIS and an NPDES permit and the percentage of all plants that they represent. Excluding Alaska, which only has one utility plant with a CWIS and an NPDES permit, the percentage of existing §316(b) facilities ranges from six percent in the Western Systems Coordinating Council (WSCC) to 58 percent in the Electric Reliability Council of Texas (ERCOT). The East Central Area Reliability Coordination Agreement (ECAR) has the highest absolute number of existing §316(b) facilities with 124, or 44 percent of all facilities, followed by the Southeastern Electric Reliability Council (SERC) with 122 facilities, or 38 percent of all facilities. The smallest percentage of water use for utilities is observed in the West and Southwest (the WSCC and the Southwest Power Pool, SPP, have the lowest percentages with six and 19 percent, respectively), where water conservation has long been an important issue.

Table 3-8: Utility Plants by NERC Region, 1998

NERC Region	Total Number of Plants	Plants with CWIS and NPDES Permit	
		Number	% of Total
ASCC	166	1	1%
ECAR	283	124	44%
ERCOT	106	61	58%
FRCC	63	32	51%
HI	16	6	38%
MAAC	121	52	43%
MAIN	196	60	31%
MAPP	398	63	16%
NPCC	372	59	16%
SERC	320	122	38%
SPP	259	50	19%
WSCC	742	48	6%
Total	3,042	678	22%

Source: Form EIA-860A, 1998; Form EIA-861, 1998.

e. Water Body and Cooling System Type

The impacts of CWISs on the aquatic habitats from which they withdraw water depend on several factors, including the type of water body, the location of the CWIS relative to sensitive biological areas, the intake flow volume, and the velocity. This section characterizes existing §316(b) utility plants with respect to two of those characteristics: water body type and cooling system type.

Table 3-9 shows that most of the existing utility plants with a CWIS and an NPDES permit draw water from a freshwater river (369, or 54 percent). The next most frequent water body types are lakes or reservoirs with 141 plants (21 percent) and estuaries or tidal rivers with 88 plants (13 percent).

The table also shows that most of these plants, 403 or 59 percent, employ a once-through cooling system. Of the plants that withdraw from an estuary, the most sensitive type of water body, only five percent use a closed cycle system while 85 percent have a once through system. In contrast, 28 percent of plants located on freshwater rivers and on lakes or reservoirs have a closed cycle system.

Table 3-9: Number of Utility Plants by Water Body Type and Cooling System Type

Water Body Type	Cooling System Type								Total
	Closed Cycle		Once Through		Combination		Unknown		
	Number	% of Total	Number	% of Total	Number	% of Total	Number	% of Total	
Estuary	4	5%	75	85%	7	8%	2	2%	88
Lake	39	28%	89	63%	12	9%	1	1%	141
Ocean	1	6%	16	89%	1	6%	0	0%	18
River	102	28%	214	58%	52	14%	1	0%	369
Other/ Unknown	22	35%	9	15%	6	10%	25	40%	62
Total	168	25%	403	59%	78	12%	29	4%	678

Source: Form EIA-767, 1997; UDI database, 1994; Form EIA-860A, 1998.

3.3.2 Existing §316(b) Nonutility Plants

EPA identified nonutility steam electric prime movers that require cooling water using information from the EIA data collection Forms EIA-860B and EIA-867.[9] These prime movers include:

- Atmospheric Fluidized Bed Combustion (AB)
- Combined Cycle – Auxiliary (CA)
- Combined Cycle – Total Unit (CC)
- Steam Turbine – Common Header (CH)
- Combined Cycle – Single Shaft (CS)
- Combined Cycle – Waste(CW)
- Steam Turbine – Geothermal (GE)
- Combined Cycle – ICG (IG)
- Nuclear BWR (NB)
- Steam Turbine Graphite Nuclear Reactor (NG)
- Nuclear HTGR (NH)
- Nuclear LWBR (NL)
- Nuclear PWR (NP)
- Nuclear Unknown (NU)
- Steam Turbine – Flourized Bed (SF)
- Steam Turbine – Solar (SS)
- Steam Turbine – Boiler (ST)

Forms EIA-860B and EIA-867 include two types of nonutilities: facilities whose primary business activity is the generation of electricity, and manufacturing facilities that operate industrial boilers in addition to their primary manufacturing processes. The discussion of existing §316(b) nonutilities focuses on those nonutility facilities that generate electricity as their primary line of business.[10] Manufacturing facilities with industrial boilers are included in the industry profiles in *Chapter 4: Profile of Manufacturing Industries*.

Using the identified list of steam electric prime movers and Form EIA-860B information on the reported operating status of units, EPA identified 422 facilities that have at least one generating unit with a steam electric prime mover. Additional information from the §316(b) Industry Screener determined that 85 of the 422 facilities operate a CWIS and hold an NPDES permit. Table 3-10 provides information on the number of parent entities, nonutility plants, and generating units, and their generating capacity in 1998. The table provides information for the industry as a whole, for the steam electric part of the industry, and for the "§316(b)" part of the industry.

[9] Form EIA-860B (Annual Nonutility Electric Generator Report) is the equivalent of Form EIA-860A for utilities. It is the annual inventory of nonutility plants and collects data on the type of prime mover, nameplate rating, energy source, year of initial commercial operation, and operating status. Form EIA-867 (Annual Nonutility Power Producer Report) is the predecessor of Form EIA-860B. Form EIA-867 contained similar, but more detailed, information to Form EIA-860B but was confidential. The EIA provided EPA with a list of nonutilities with steam electric prime movers from the 1996 Form EIA-867, which formed the basis for the EPA's screener questionnaire and this analysis.

[10] EPA identified manufacturing facilities operating *steam electric* industrial boilers using SIC code information from Form EIA-867. Those facilities were removed from the analysis. The discussion of steam electric nonutilities and nonutilities with CWIS and NPDES permit, therefore, only includes facilities with electricity generation as their main line of business. However, the same information was not available for facilities with non-steam prime movers. Industry totals, therefore, include industrial boilers.

Table 3-10: Number of Nonutilities, Nonutility Plants, Units, and Capacity, 1998

	Total†	Total Steam Electric Nonutilities††	Nonutilities with CWIS and NPDES Permit††
Parent Entities	1,443	349	62
Plants	1,986	422	85
Units	5,161	555	117
Nameplate Capacity (MW)	97,543	39,260	21,627

† Includes all facilities with at least one non-retired unit in Form EIA-860B data (both nonutilities and industrial boilers).
†† Includes only nonutility plants generating electricity as their primary line of business.

Source: Form EIA-860, 1998; Form EIA-860B, 1998; Form EIA-867, 1996; EPA Industry Screener Questionnaire: Phase I Cooling Water Intake Structures, 1999.

a. Ownership Type

Nonutility power producers that generate electricity as their main line of business fall into two different categories: "original nonutility plants" and "former utility plants."

❖ ***Original nonutility plants***

For the purposes of this analysis, original nonutility plants are those that were originally built by a nonutility. These plants primarily include facilities qualifying under the Public Utility Regulatory Policies Act of 1978 (PURPA), cogeneration facilities, independent power producers, and exempt wholesale generators under the Energy Policy Act of 1992 (EPACT).

EPA identified original nonutility plants with a CWIS and an NPDES permit through the §316(b) *Industry Screener Questionnaire: Phase I Cooling Water Intake Structures* which was sent to all nonutilities with a steam electric prime mover listed in the 1996 Form EIA-867. This profile further differentiates original nonutility plants by their primary Standard Industrial Classification (SIC) code, as reported in the screener questionnaire. Reported SIC codes include:

- 4911 – Electric Services
- 4931 – Electric and Other Services Combined
- 4939 – Combination Utilities, Not Elsewhere Classified
- 4953 – Refuse Systems
- 4961 – Steam and Air-Conditioning Supply

❖ ***Former utility plants***

Former utility plants are those that used to be owned by a utility power producer but have been sold to a nonutility as a result of industry deregulation. These were identified from Form EIA-860B by their plant code.[11]

Table 3-11 shows that original nonutilities account for the vast majority of plants (1,942 out of 1,986, or 98 percent). Only 44 out of the 1,986 nonutility plants, or 2 percent, were formerly owned by utilities. However, these 44 facilities account for more than 23 percent of all nonutility generating capacity. Eighty-five of the 1,986 nonutility plants operate a CWIS and hold an NPDES permit. Most of these §316(b) facilities (61, or 72 percent) are original nonutility plants. Only 24 of the 85 §316(b) nonutility plants are former utility plants, but they account for 78 percent of all §316(b) nonutility capacity.

The table also shows that only three percent of all original nonutility plants have a CWIS and an NPDES permit,[12] compared to 55 percent of all former utility plants.

[11] Utility plants have an identification code number that is less than 10,000 whereas nonutilities have a code number greater than 10,000. When utility plants are sold to nonutilities, they retain their original plant code.

[12] This percentage understates the true share of §316(b) nonutility plants because the total number of plants includes industrial boilers while the number of §316(b) nonutilities does not.

Table 3-11: Existing Nonutility Firms, Plants, and Capacity by SIC Code, 1998

SIC Code	Firms			Plants			Capacity (MW)		
	Total Number of Firms	Firms with Plants with CWIS and NPDES		Total Number of Plants	Plants with CWIS and NPDES		Total Capacity	Capacity with CWIS and NPDES	
		Number	% of Total		Number	% of Total		MW	% of Total
4911	1,429†	25	3%	1,942	29	3%	75,020,663	1,930,113	6%
4931		11			15			1,981,596	
4939		4			5			377,430	
4953		7			12			404,555	
4961		1			1			8,332	
Former Utility Plants	14††	14	100%	44	24	55%	22,522,775	16,924,508	75%
Total	1,443	62	4%	1,986	85	4%	97,543,438	21,626,535	22%

† Individual numbers may not add up to total due to individual rounding.

†† Three firms owning former utility plants do not operate a plant with a CWIS and an NPDES permit. However, three former utility plants with a CWIS and an NPDES permit are not listed in Form EIA-860B. While the number of firms with plants with CWIS and NPDES permit was adjusted to reflect the owners of the three missing plants, the total number of firms was not. The real percentage of firms that own former utility plants with a CWIS and an NPDES permit is therefore less than 100 percent.

Source: Form EIA-860B, 1998.

b. Ownership Size

EPA used the Small Business Administration (SBA) small entity size standards to determine the number of existing §316(b) nonutility plants owned by small firms. Table 4-12 shows that of the 61 original nonutility plants with CWISs and NPDES permits 17 percent are owned by a small entity. Another 26 percent are owned by a firm of unknown size which may also qualify as a small entity.

Information on the business size for former utility plants was not readily available. EPA classified 14 facilities as owned by a large firm because their plant-level electricity generation in 1997 exceeded 4 million MWh, the SBA threshold for SIC code 4911. All other facilities were classified as "unknown" for the purposes of this profile.

Table 4-12: Number of Nonutility Plants with CWIS and NPDES Permit by Firm Size, 1998

SIC Code	Large		Small		Unknown		Total
	No.	% of SIC	No.	% of SIC	No.	% of SIC	
4911	14	48%	6	20%	9	32%	29
4931	10	69%	2	15%	2	15%	15
4939	3	75%	1	25%	0	0%	5
4953	6	50%	1	10%	5	40%	12
4961	1	100%	0	0%	0	0%	1
Total Original Nonutilities	34	57%	10	17%	16	26%	61
Former Utility Plants[†]	14	58%	0	0%	10	42%	24

† Individual numbers may not add up to total due to individual rounding.

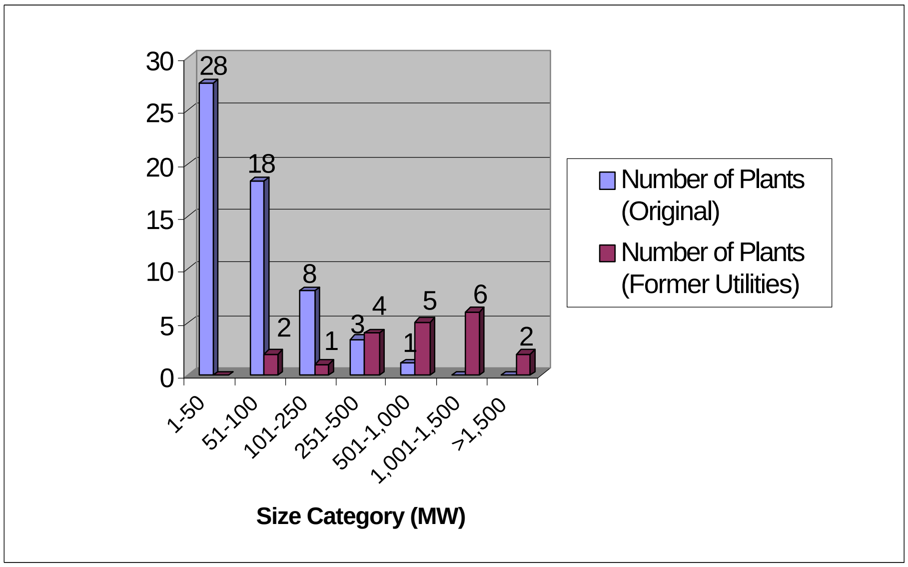
† Information on the size of nonutility firms owning former utility plants was not available. Fourteen facilities were classified as large because their plant-level electricity generation in 1997 exceeded 4 million MWh, the SBA threshold for SIC code 4911. All other facilities were classified as "unknown."

Source: EPA Industry Screener Questionnaire: Phase I Cooling Water Intake Structures, 1999; D&B Database, 1999.

c. Plant Size

EPA also analyzed the steam electric nonutilities with a CWIS and an NPDES permit with respect to their generating capacity. Figure 3-7 shows that the original nonutility plants are much smaller than the former utility plants. Of the 61 original utility plants, 28 (46 percent) have a total nameplate capacity of 50 MW or less and 46 (75 percent) have a capacity of 100 MW or less. No original nonutility plant has a capacity of more than 1,000 MW. In contrast, only three (13 percent) former utility plants are smaller than 250 MW while 13 (54 percent) are larger than 500 MW and eight (33 percent) are larger than 1,000 MW.

Figure 3-6: Distribution of Existing Nonutility Plants with In-Scope Characteristics by Capacity, 1998



Data for 78 nonutility plants. Seven plants are listed without steam electric capacity in 1998 EIA-860B.

Source: *Form EIA-860B, 1998; EPA Industry Screener Questionnaire: Phase I Cooling Water Intake Structures, 1999.*

d. Geographic Distribution

Table 3-13 shows the distribution of existing §316(b) nonutility plants by NERC region. The figure shows that the Northeast Power Coordinating Council (NPCC) has the highest absolute number of existing §316(b) nonutility plants with 33, or 39 percent of all 85 plants with a CWIS and an NPDES permit, followed by the Western System Coordinating Council (WSCC) with 12 plants.

The East Central Area Reliability Coordination Agreement (ECAR) and the Mid-Atlantic Area Council (MAAC) have the largest percentage of plants with a CWIS and an NPDES permit compared to all nonutility plants, with 11 percent each.[13]

Table 3-13: Nonutility Plants by NERC Region, 1998

NERC Region	Total Number of Plants	Plants with CWIS & NPDES Permit	
		Number	% of Total
ASCC	28	1	4%
ECAR	101	11	11%
ERCOT	40	0	0%
FRCC	62	2	4%
HI	8	0	0%
MAAC	95	10	11%
MAIN	105	1	1%
MAPP	74	1	2%
NPCC	384	33	9%
SERC	246	8	3%
SPP	55	0	0%
WSCC	585	12	2%
Not Available	203	4	2%
Total	**1,986**	**85**	**4%**

Source: Form EIA-860, 1998; Form EIA-860B, 1998; EPA Industry Screener Questionnaire: Phase I Cooling Water Intake Structures, 1999.

[13] As explained earlier, the total number of plants includes industrial boilers while the number of plants with a CWIS and an NPDES permit does not. Therefore, the percentages are likely higher than presented.

e. Water Body and Cooling System Type

Table 3-14 shows the distribution of existing §316(b) nonutility plants by type of water body and cooling system. Table 3-9 shows that most of the original nonutility plants with a CWIS and an NPDES permit draw water from a freshwater river (38, or 62 percent) while most of the former utility plants withdraw from an ocean (8, or 33 percent).

The table also shows that most of the original nonutility plants (37 or 60 percent) employ a closed cycle cooling system while most of the former utility plants (18, or 75 percent) have a once through system. Ten original nonutility plants withdraw from an estuary, with only two of them employing a closed cycle system. Among the former utility plants, five withdraw from an estuary, all with a once through system.

Table 3-14: Number of Nonutility Plants by Water Body Type and Cooling System Type

Water Body Type	Cooling System								Total
	Closed Cycle		Once Through		Combination		Unknown		
	Number	% of Total	Number	% of Total	Number	% of Total	Number	% of Total	
Original Nonutilities									
Estuary	2	22%	8	78%	0.00	0%	0	0%	10
Lake	10	82%	2	18%	0.00	0%	0	0%	13
Ocean	0	0%	0	0%	0.00	0%	0	0%	0
River	24	64%	13	33%	1.15	3%	0	0%	38
Other/ Unknown	0	0%	0	0%	0.00	0%	0	0%	0
Total	37	60%	23	38%	1	2%	0	0%	61
Former Utility Plants									
Estuary	0	0%	5	100%	0	0%	0	0%	5
Lake	1	100%	0	0%	0	0%	0	0%	1
Ocean	0	0%	8	100%	0	0%	0	0%	8
River	3	50%	3	50%	0	0%	0	0%	6
Other/ Unknown	0	0%	2	50%	0	0%	2	50%	4
Total	4	17%	18	75%	0	0%	2	8%	24

Source: Form EIA-860B, 1998; EPA Industry Screener Questionnaire: Phase I Cooling Water Intake Structures, 1999.

3.4 INDUSTRY OUTLOOK

This section discusses industry trends that are currently affecting the structure of the electric power industry and may therefore affect the magnitude of impacts from §316(b) regulation. The most important change in the electric power industry is deregulation – the transition from a highly regulated monopolistic to a less regulated, more competitive industry. Subsection 3.4.1 discusses the current status of deregulation. Subsection 3.4.2 presents a summary of forecasts from the Annual Energy Outlook 2000.

3.4.1 Current Status of Industry Deregulation

The electric power industry is evolving from a highly regulated, monopolistic industry with traditionally-structured electric utilities to a less regulated, more competitive industry.[14] The industry has traditionally been regulated based on the premise that the supply of electricity is a natural monopoly, where a single supplier could provide electric services at a lower total cost than could be provided by several competing suppliers. Today, the relationship between electricity consumers and suppliers is undergoing substantial change. Some states have implemented plans that will change the procurement and pricing of electricity significantly, and many more plan to do so during the first few years of the 21st century (Beamon, 1998).

a. Key Changes in the Industry s Structure

Industry deregulation already has and continues to fundamentally change the structure of the electric power industry. Some of the key changes include:

- ***Provision of services:*** Under the traditional regulatory system, the generation, transmission, and distribution of electric power were handled by vertically-integrated utilities. Since the mid-1990s, federal and state policies have led to increased competition in the generation sector of the industry. Increased competition has resulted in a separation of power generation, transmission, and retail distribution services. Utilities that provide transmission and distribution services will continue to be regulated and will be required to divest of their generation assets. Entities that generate electricity will no longer be subject to geographic or rate regulation.

- ***Relationship between electricity providers and consumers:*** Under traditional regulation, utilities were granted a geographic franchise area and provided electric service to all customers in that area at a rate approved by the regulatory commission. A consumer's electric supply choice was limited to the utility franchised to serve their area. Similarly, electricity suppliers were not free to pursue customers outside their designated service territories. Although most consumers will continue to receive power through their local distribution company (LDC), retail competition will allow them to select the company that generates the electricity they purchase.

- ***Electricity prices:*** Under the traditional system, state and federal authorities regulated all aspects of utilities' business operations, including their prices. Electricity prices were determined administratively for each utility, based on the average cost of producing and delivering power to customers and a reasonable rate of return. As a result of deregulation, competitive market forces will set generation prices. Buyers and sellers of power will negotiate through power pools or one-on-one to set the price of electricity. As in all competitive markets, prices will reflect the interaction of supply and demand for electricity. During most time periods, the price of electricity will be set by the generating unit with the highest operating costs needed to meet spot market generation demand (i.e., the "marginal cost" of production) (Beamon, 1998).

b. New Industry Participants

The Energy Policy Act of 1992 (EPACT) provides for open access to transmission systems, to allow nonutility generators to enter the wholesale market more easily. In response to these requirements, utilities are proposing to form Independent System Operators (ISOs) to operate the transmission grid, regional transmission groups, and open access same-time information systems (OASIS) to inform competitors of available capacity on their transmission systems. The advent of open transmission access has fostered the development of power marketers and power brokers as new participants in the electric power industry. Power marketers buy and sell wholesale electricity and fall under the jurisdiction of the Federal Energy Regulatory Commission (FERC), since they take ownership of

[14] Several key pieces of federal legislation have made the changes in the industry's structure possible. The ***Public Utility Regulatory Policies Act*** (PURPA) of 1978 opened up competition in the generation market by creating a class of nonutility electricity-generating companies referred to as "qualifying facilities." The ***Energy Policy Act*** (EPACT) of 1992 removed constraints on ownership of electric generation facilities, and encouraged increased competition in the wholesale electric power business (Beamon, 1998).

electricity and are engaged in interstate trade. Power marketers generally do not own generation or transmission facilities or sell power to retail customers. A growing number of power marketers have filed with the FERC and have had rates approved. Power brokers do not take ownership of electricity and are not regulated by the FERC.

c. State Activities

Many states are taking steps to promote competition in their electricity markets. The status of these efforts varies across states. Some states are just beginning to study what a competitive electricity market might mean; others are beginning pilot programs; still others have designed restructured electricity markets and passed enabling legislation. The following states have already enacted restructuring legislation (U.S. DOE, 2000b):

- Arizona
- Arkansas
- California
- Connecticut
- Delaware
- District of Columbia
- Illinois
- Maine
- Maryland
- Massachusetts
- Michigan
- Montana
- Nevada
- New Hampshire
- New Jersey
- New Mexico
- Ohio
- Oklahoma
- Oregon
- Pennsylvania
- Rhode Island
- Texas
- Virginia
- West Virginia

Even in states where consumer choice is available, important aspects of implementation may still be undecided. Key aspects of implementing restructuring include treatment of ***stranded costs***, pricing of transmission and distribution services, and the design market structures required to ensure that the benefits of competition flow to all consumers (Beamon, 1998).

3.4.2 Energy Market Model Forecasts

This section discusses forecasts of electric energy supply, demand, and prices based on data and modeling by the EIA and presented in the *Annual Energy Outlook 2000* (U.S. DOE, 1999b). The EIA models future market conditions through the year 2020, based on a range of assumptions regarding overall economic growth, global fuel prices, and legislation and regulations affecting energy markets. The projections are based on the results from EIA's National Energy Modeling System (NEMS). The following discussion present EIA's reference case results.

❖ *Electricity Demand*

EIA expects electricity demand to grow by approximately 1.4 percent annually between 1998 and 2020. This growth is driven by an estimated 1.5 percent annual increase in the demand for electricity by residential customers. Residential demand growth results from an increase in the number of households, particularly in the south where most new homes use central air conditioning, as well as increased penetration of consumer electronics. EIA expects electricity demand from the commercial sector to increase by 1.2 percent annually over the same forecast period, largely in response to an annual increase in commercial floor space. Industrial electricity demand is expected to increase by 1.3 percent annually, due mostly to an increase in industrial output.

❖ *Capacity Retirements*

EIA expects total nuclear generation capacity to decline by an estimated 41 percent (40 gigawatts) between 1998 and 2020 due to nuclear power plant retirement. To produce this estimate, EIA compared the costs associated with extending the life of aging nuclear generation facilities to the cost of building new capacity to meet the need for additional electricity generation. EIA determined that plant aging related investments for most nuclear plants would exceed the cost of building new capacity. EIA also expects total fossil fuel-fired generation capacity to decline due to retirements. Retirements of fossil-steam plants is estimated to decrease capacity in this sector by approximately 16 percent (i.e., 28 gigawatts) over the same time period.

❖ *Capacity Additions*

Additional generation capacity will be needed to meet the estimated growth in electricity demand and offset the retirement of existing capacity. The EIA expects plant owners to employ other options, such as life extensions or repowering, before building new capacity. The Agency forecasts that utilities will choose technologies for new generation capacity that seek to minimize cost while meeting environmental and emission constraints. Of the new capacity forecast to come on-line between 1998 and 2020, 90 percent is expected to be combined-cycle or combustion turbine technology. This additional capacity is expected to be fueled by natural gas or both oil and natural gas, and to supply primarily peak and intermediate capacity. Another seven percent of additional capacity is expected to be provided by new coal-fired plants, while the remaining three percent is forecast to come from renewable technologies.

❖ *Electricity Generation*

EIA expects increased electricity generation from both natural gas and coal-fired plants to meet growing demand and to offset lost capacity due to plant retirements. Coal-fired plants are expected to continue to account for approximately half of the industry's total generation. Although coal-fired generation is predicted to increase steadily between 1998 and 2020, its share of total generation is expected to decrease from 52 percent to an estimated 49 percent. This decrease in the share of coal generation is in favor of less capital-intensive and more efficient natural gas generation technologies. The share of total generation associated with gas-fired technologies is forecast to increase from approximately 14 percent in 1998 to an estimated 31 percent in 2020, replacing nuclear power as the second largest source of electricity generation. Generation from oil-fired plants is expected to decline over the forecast period as oil-fired steam generators are replaced by gas turbine technologies.

❖ *Electricity Prices*

EIA expects the average wholesale price of electricity, as well as the price paid by customers in each sector (residential, commercial, and industrial), to decrease between 1998 and 2020 as a result of competition among electricity suppliers. Specific market restructuring plans differ from state to state. Some states have begun deregulating their electricity markets; EIA expects most states to phase in increased customer access to electricity suppliers. Increases in the cost of fuels like natural gas and oil are not expected to increase electricity prices; these increases are expected to be offset by reductions in the price of other fuels and shifts to more efficient generating technologies.

Glossary

Combined-Cycle Turbine: An electric generating technology in which electricity is produced from otherwise lost waste heat exiting from one or more gas (combustion) turbines. The exiting heat is routed to a conventional boiler or to heat recovery steam generator for utilization by a steam turbine in the production of electricity. This process increases the efficiency of the electric generating unit.

Distribution: The portion of an electric system that is dedicated to delivering electric energy to an end user.

Electricity Available to Consumers: Power available for sale to customers. Approximately 8 to 9 percent of net generation is lost during the transmission and distribution process.

Energy Policy Act (EPACT): In 1992 the EPACT removed constraints on ownership of electric generation facilities and encouraged increased competition on the wholesale electric power business.

Gas Combustion Turbine: A gas turbine typically consisting of an axial-flow air compressor and one or more combustion chambers, where liquid or gaseous fuel is burned and the hot gases are passed to the turbine. The hot gases expand to drive the generator and are then used to run the compressor.

Generation: The process of producing electric energy by transforming other forms of energy. Generation is also the amount of electric energy produced, expressed in ***watthours (Wh)***.

Gross Generation: The total amount of electric energy produced by the generating units at a generating station or stations, measured at the generator terminals.

Internal Combustion Engine: An internal combustion engine has one or more cylinders in which the process of combustion takes place, converting energy released from the rapid burning of a fuel-air mixture into mechanical energy. Diesel or gas-fired engines are the principal fuel types used in these generators.

Kilowatthours (kWh): One thousand ***watthours (Wh)***.

Nameplate Capacity: The amount of electric power delivered or required for which a generator, turbine, transformer, transmission circuit, station, or system is rated by the manufacturer.

Net Capacity: The amount of electric power delivered or required for which a generator, turbine, transformer, transmission circuit, station, or system is rated by the manufacturer, exclusive of station use, and unspecified conditions for a given time interval.

Net Generation: Gross generation minus plant use from all plants owned by the same utility.

Nonutility: A corporation, person, agency, authority, or other legal entity or instrumentality that owns electric generating capacity and is not an electric utility. Nonutility power producers include qualifying cogenerators, qualifying small power producers, and other nonutility generators (including independent power producers) without a designated franchised service area, and which do not file forms listed in the Code of Federal Regulations, Title 18, Part 141. (http://www.eia.doe.gov/cneaf/electricity/epav1/html/Glossary.htm)

Other Prime Movers: Methods of power generation other than ***steam turbine***, ***combined-cycle***, ***gas combustion turbine***, ***internal combustion engine***, and ***water turbine***. Other prime movers include: geothermal prime mover, solar prime mover, wind prime mover, and biomass prime mover.

Prime Movers: The engine, turbine, water wheel or similar machine that drives an electric generator. Also, for reporting purposes, a device that directly converts energy to electricity, e.g., photovoltaic, solar, and fuel cell(s).

Public Utility Regulatory Policies Act (PURPA): In 1978 PURPA opened up competition in the generation market by creating a class of nonutility electricity-generating companies referred to as "qualifying facilities."

Reliability: Electric system reliability has two components: adequacy and security. Adequacy is the ability of the electric system to supply customers at all times, taking into account scheduled and unscheduled outages of system facilities. Security is the ability of the electric system to withstand sudden disturbances, such as electric short circuits or unanticipated loss of system facilities. (http://www.eia.doe.gov/oiaf/elepri97/glossary.html)

Steam Turbine: A generating unit in which the prime mover is a steam turbine. The turbines convert thermal energy (steam or hot water) produced by generators or boilers to mechanical energy or shaft torque. This mechanical energy is used to power electric generators, including combined cycle electric generating units, which convert the mechanical energy to electricity.

Stranded Costs: The difference between revenues under competition and costs of providing service, including the inherited fixed costs from the previous regulated market. (http://www.eia.doe.gov/oiaf/elepri97/glossary.html)

Transmission: The movement or transfer of electric energy over an interconnected group of lines an associated equipment between points of supply and points at which it is transformed for delivery to consumers, or is delivered to other electric systems. Transmission is considered to end when the energy is transformed for distribution to the consumer.

Utility: A corporation, person, agency, authority, or other legal entity or instrumentality that owns and/or operates facilities within the United States, its territories, or Puerto Rico for the generation, transmission, distribution, or sale of electric energy primarily for use by the public and files forms listed in the Code of Federal Regulations, Title 18, Part 141. Facilities that qualify as cogenerators or small power producers under the Public Utility Regulatory Policies Act (PURPA) are not considered electric utilities. (http://www.eia.doe.gov/cneaf/electricity/epav1/html/Glossary.htm)

Water Turbine: A unit in which the turbine generator is driven by falling water.

Watthour (Wh): An electrical energy unit of measure equal to 1 ampere flowing under pressure of 1 volt at unity power factor.

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